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December 17, 2018 Laura K. Perry

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Environmental Protection Agency Submitted via US Mail, e-mail,

Docket No. EPA -HQ -OAR -2017-0483 and the Federal eRulemaking

Attn: Karen Marsh, Sector Policies and Programs Division Portal

Mail Code 28221T

1200 Pennsylvania Ave. NW

Washington D.C. 20406

Subject: Docket ID No. EPA -HQ -OAR -2017-0483; Comments on Oil and Natural Gas

Sector: Emission Standards for New and Modified Sources (Federal Register, Vol.

83, No. 199, October 15, 2018)

Dear Ms. Marsh:

ConocoPhillips Alaska, Inc. (CPAI) is pleased to submit the attached comments on the above

referenced proposed new source performance standards (40 CFR 60, Subpart 0000a). CPAI

produces oil from both the Kuparuk and Alpine oil fields and has equity interest in the Prudhoe

Bay oil field. As such, we are the largest producer of oil in Alaska, so we have a significant interest

in the proposed 0000a rule.

CPAI supports the comments submitted by the American Petroleum Institute (API). CPAI submits

this separate letter to focus on issues specific to the Arctic conditions that affect North Slope oil

field operations.

The attached comments focus on the following areas:

1. Alaska North Slope Compressor Station Initial and Routine Survey Deadlines

2. Well Site and Compressor Station Leak Detection Delay of Repair Provisions

3. Well Site Leak Detection and Repair Modification Criteria

4. Alaska North Slope -Specific Leak Data and Cost Effectiveness of Leak Detection and Repair

Thank you for this opportunity to comment. Please do not hesitate to call me if you have any

questions or need more infoimation to support our comments.

ConocoPhillips Alaska, Inc.

Comments on Proposed 40 CFR 60, Subpart OOOOa

Docket ID EPA-HQ-OAR-2017-0483

December 17, 2018

1. Alaska North Slope Compressor Station Initial and Routine Survey Deadlines

ConocoPhillips Alaska, Inc. (CPAI) supports the proposed revisions to the initial survey and

routine survey deadlines for compressor station affected facilities located on the Alaska North

Slope. Under the proposed rules, the deadline for initial surveys would be within 6 months or by

June 30, whichever is later, for compressor stations that startup between September and March, or

within 60 days for compressor stations that startup between April and August; and the deadline for

routine surveys would be annual. This revision will align the deadlines for compressor station

affected facilities with the deadlines for well site affected facilities, which were modified on March

12, 2018.1 This alignment is important to address the technical obstacles to executing surveys

during the winter season on the Alaska North Slope.

2. Well Site and Compressor Station Leak Detection Delay of Repair Provisions

EPA has solicited comments on the Delay of Repair (DOR) provisions applicable to "well site"

(WS) and "compressor station" (CS) fugitive emission affected facilities as defined under 40 CFR

60.5365a(i) and (j).2

The current NSPS OOOOa DOR provisions for WS and CS affected facilities, as amended March

12, 2018, establishes a deadline of no later than two years to repair equipment placed on DOR:

If the repair or replacement is technically infeasible, would require a vent blowdown, a

compressor station shutdown, a well shutdown or well shut-in, or would be unsafe to repair

during operation of the unit, the repair or replacement must be completed during the next

scheduled compressor station shutdown, well shutdown, well shut-in, after a planned vent

blowdown or within 2 years, whichever is earlier.[3]

In the final NSPS OOOOa rule promulgated on June 3, 2016, the EPA indicated that the intent of

the two-year deadline was to provide companies with sufficient time "to avoid the excess

emissions (and costs) of prematurely forcing a shutdown"4 when making a repair on operating

equipment would be technically infeasible or unsafe. EPA noted that the supporting basis for the

two-year deadline in the DOR provisions was based on "currently available information,"

suggesting that one of the repair events described in 40 CFR 60.5397a(h)(2) "is likely to occur

within that two-year timeframe."5

1 83 FR 10628.

2 83 FR at page 52076.

3 40 CFR 60.5397a(h)(2) (emphasis added).

4 81 FR at page 35858.

5 81 FR at page 35863.

The two-year deadline is based on a faulty assumption that shut-downs occurs at least every two

years. On the Alaska North Slope, integrated production operations occur in isolation from other

infrastructure, and facility shut-downs are major planning events that result in suspension of many

operational activities, require coordination across multiple production units, and do not occur

every two years. Requiring a repair before a scheduled shut-down can impose a very high cost on

operators and result in additional blow-down of lines, which unnecessarily causes more methane

emissions. The-two year deadline is in some cases a cause of additional methane emissions, which

undermines the goal of safe and cost-effective reduction of methane emissions.

Using the Kuparuk River Unit (KRU) as an example, one major component of the integrated

operations, a central processing facility (CPF), supports 13 to 18 distinct well pads--each

containing 15 to 66 production wells for a total of many hundreds of wells (producers and injectors)

supported by a single facility. Given the scale of affected facilities, shutdown events at Kuparuk

are formal maintenance turnaround programs that directly employ 60 to 100 personnel as well as

indirectly involve many other support personnel depending on the shutdown scope. These

programs require rigorous planning, budgeting, and coordination with production,

maintenance/reliability, transportation/logistics, and business planning functional groups. Planned

shutdown activities at Kuparuk and other North Slope facilities are more similar to turnaround

activities conducted at petroleum refineries than shutdowns conducted at well pads in other

locations.

Due to the complexity and the coordination required for these events, planned shutdown activities

for shared production infrastructure can occur at frequencies of three years or more, depending on

the equipment. CPFs at Kuparuk generally undergo process safety protection systems preventive

maintenance every three years (one CPF each year) to minimize overall impact on field operations

and efficiently use available resources to complete work safely. These preventive maintenance

events include initiating the emergency shutdown and facility blowdown systems. Planned

shutdowns for other scopes of work such as major equipment replacement or upgrade occur at less

frequent intervals and may or may not be able to be coordinated with process safety related

shutdowns.

Failure to properly coordinate these events can result in significant disruption of operations and

create safety issues for maintenance personnel. Shutdowns affect all production and well support

systems and as such require extensive planning to minimize the impact to the overall field as well

as to stakeholders (such as the Trans-Alaska Pipeline System). Shutdowns are complicated by the

short summer season when ambient temperatures allow wells to be idled without freezing. They

are also subject to long materials procurement lead times and shipping delays. Work is often

limited by labor and support equipment resources available in the field. Shutdowns also typically

require time to secure permits from regulatory agencies for activities like off-road travel, handling

and disposal of hazardous materials, safely flaring gases in affected process equipment that could

include several miles of pipeline, and planning for, preventing, and reacting to releases or spills.

In some cases, shut downs can affect local communities, which are left without their source of gas

for space and water heating during the shut-down.

While many fugitive emission repairs can be safely executed while equipment is operating, certain

fugitive emission equipment require a shutdown to safely execute the repair. During these repairs,

the equipment is de-energized and blown down to create a safe environment to work on the

component. It is not feasible for CPAI to meet the current DOR two-year deadline for equipment

that does not have a planned shutdown scheduled within that time period. The current rule,

including the proposed amendments, provide no clear process for requesting a variance from the

deadline. The result could be line blowdowns to complete a repair, even if the repair could be done

during a facility shut-down schedule to occur within just a few weeks beyond the two-year

deadline. In that case, emissions and costs are increased solely to meet an arbitrary two-year

deadline.

CPAI requests that EPA change the DOR provisions described in 40 CFR 60.5397a(h)(2) to

remove the two-year deadline. With this change, the regulation would continue to meet EPA's

objective for mandating that the components placed on DOR are repaired during the next

scheduled shutdown. Additionally, this would provide continuity with EPA's traditional Method

21-based NSPS leak detection and repair (LDAR) programs such as NSPS VV/VVa and NSPS

GGG/GGGa. One example of that program is in 40 CFR § 60.482-9a(a), which provides:

Delay of repair of equipment for which leaks have been detected will be allowed if repair

within 15 days is technically infeasible without a process unit shutdown. Repair of this

equipment shall occur before the end of the next process unit shutdown. Monitoring to

verify repair must occur within 15 days after startup of the process unit. [Emphasis added.]

The deadline of "the next process unit shutdown" without a two-year mandate is a sufficient and

appropriate deadline that serves the intended purposes. It has been used in analogous programs

and should be used in the OOOOa program. Dropping the two-year mandate would promote

consistency within the NSPS OOOO/OOOOa rules where natural gas processing plants and the

closed vent system repair requirements allows repairs to be conducted during the next scheduled

shutdown and do not impose a two-year or any other arbitrary deadline. In 40 CFR §

60.5416a(b)(10), for example, and also in subsection (c)(5), the regulatory language is as follows:

Delay of repair. Delay of repair of a closed vent system or cover for which leaks or defects

have been detected is allowed if the repair is technically infeasible without a shutdown, or

if you determine that emissions resulting from immediate repair would be greater than the

fugitive emissions likely to result from delay of repair. You must complete repair of such

equipment by the end of the next shutdown. [Emphasis added.]

Similar language should be used in 40 CFR 60.5397a(h)(2). The annual DOR reporting

requirements under 40 CFR 60.5420a(b)(7) will allow EPA to monitor components placed on

DOR to ensure the time duration between planned shutdown events are not excessive or

unnecessarily prolonged.

3. Well Site LDAR Modification Criteria

EPA has solicited comments on the rationale for the definition of "modification" under the WS

affected facility,6 the "well site" definition as it relates to injection wells,7 and the "startup of

production" for wells that are not hydraulically fractured.8 We recommend a change to ensure that

drilling a solid waste disposal well does not trigger LDAR requirements for an entire well site.

CPAI operates onshore production assets in the remote areas of the Alaska North Slope that do not

have the waste management infrastructure found at most other drilling locations in the United

States. Certain North Slope production areas, such as CPAI's Colville River Unit, are accessible

only by a seasonal ice road, aircraft, or ocean vessel. Therefore, CPAI must manage disposal of

wastes locally in order to facilitate continued production operations. Waste solids and spill cleanup

materials, in addition to produced water (saltwater) co-produced with oil and natural gas, are

typically disposed of in waste injection wells. These materials consist of non-hazardous solid waste

where no gas volumes are injected into the waste disposal well. The wastes are routinely sampled

and characterized under the federal and state solid waste and underground injection programs.

The current NSPS OOOOa "well site" affected facility modification criteria indicate that drilling

a new "well" at an existing WS constitutes a "modification" and thereby triggers the "well site"

LDAR requirements. Specifically, 40 CFR 60.5365a(i)(3) provides: "For purposes of §60.5397a,

a "modification" to a well site occurs when: (i) A new well is drilled at an existing well site[.]"

The term "well" is broadly defined in 40 CFR 60.5430a to include injection wells: "Well means a

hole drilled for the purpose of producing oil or natural gas, or a well into which fluids are injected."

This reference to injection wells could trigger the NSPS OOOOa LDAR requirements for drilling

waste injection wells utilized for solid waste disposal.

CPAI recommends that EPA amend the language in 40 CFR 60.5365a(i)(3)(i) to clarify the scope

of newly drilled injection wells that constitute a modification under the "well site" LDAR affected

facility. This clarification should specific that a modification under the OOOOa rule is triggered

by an injection well only when the well will (1) inject gas volumes for storage or disposal, (2)

inject gas volumes for artificial lift, (3) inject gas or liquid volumes for enhanced oil recovery, or

(4) inject gas volumes for maintenance of reservoir pressures. Using this approach addresses the

problem in a targeted way. The existing definition of "well" and "well site" would not need to be

changed, injection wells which have the potential to increase fugitive component counts or

increase production rates will be regulated under the NSPS OOOOa LDAR program, but drilling

a solid waste injection well would not trigger OOOOa LDAR requirements.

4. Alaskan North Slope-Specific Leak Data and Cost Effectiveness of LDAR

EPA solicited information regarding the cost-effectiveness of fugitive emissions monitoring

programs for WSs and CSs located on the Alaskan North Slope, noting: "Specific information that

distinguishes differences in cost realized by sites located on the Alaskan North Slope from our

6 83 FR at page 52072.

7 83 FR at page 52077.

8 83 FR at page 52078.

model plant estimates would be useful."9 As described below, the model plants used for both WSs

and CSs are not representative of Alaska North Slope facilities. The model plants are undersized,

the cost of LDAR is underestimated, and the estimated leak rate is grossly overestimated.

Model Plant Comparison

Under EPA's technical supporting document, the majority of CPAI's WSs would be categorized

as a "non-low production oil well site with GOR >300." CPAI's CSs could possibly be categorized

as a "gathering and boosting" stations, although this definition does not accurately represent

CPAI's facilities as the gas that is handled by the CPFs does not go to a natural gas processing

plant. Instead, the gas is either used onsite for fuel or is sent back out to a WS to be reinjected for

enhanced oil recovery. Table 1 below compares the model plant for these two scenarios to the

facilities located on the Alaska North Slope.

Table 1: Model Plant Comparison

EPA

Estimated

Average

Components

CPAI Alaska

North Slope

Estimated

Average

Components

Well Site Non-Low Production Oil with

Associated Gas Well Site

(>300 GOR) Model Plant

198 7,073

Compressor

Station

Gathering and Boosting

Station Model Plant

3901 >46,525

EPA's model plant assumes two wellheads per WS. CPAI estimates 36 wellheads per site on the

Alaska North Slope. The estimate of 7,073 components is the average number of components

based on actual component counts from three WSs (Site 1: 4,495, Site 2: 9,305, Site 3: 7,420).

These counts were obtained from Part 2 of the Section 114 Information Collection Request (ICR),

dated November 14, 2016 (subsequently withdrawn on March 7, 2017). All other CPAI WSs are

similar in nature to these three sites, therefore this average is a good representation

of a typical

Alaska North Slope WS operated by CPAI. Other Alaska North Slope WSs would typically be

similar.

CPAI does not have actual component counts for the CPFs. As these facilities are oil production

facilities, they encompass much more equipment than a simple gathering and boosting CS. 46,525

components is almost certainly a low estimate. This estimate is based on an assumption that a CPF

would be at least five times larger than Well Site 2 listed in the paragraph above. A North Slope

processing facility is more similar (component count wise) to a refinery than to a typical, non-

Alaska North Slope CS.

9 83 FR at page 52072.

A more detailed description of CPAI WS and CPFs can be found in our original comments on the

2015 Draft OOOOa rule submitted to EPA on December 4, 2015. Based on those original

comments and the information provided above, it is clear that EPA's model plants are not fair

representations WSs and CSs for facilities on the Alaska North Slope.

As detailed in our original comments on the 2015 Draft OOOO rule, EPA has acknowledged in

previous rulemakings that working on the Alaska North Slope involves higher costs than in other

locations due to the remote nature of the operations. Some specific costs are outlined in Table 2;

these costs are not inclusive (e.g., the cost to create the emissions monitoring plan and implement

the program are not included), but they highlight some unique differences. CPAI currently operates

55 WSs and 4 CPFs that may be considered CSs. Thirty-four WSs have already triggered LDAR;

no CPFs have triggered LDAR.

Table 2: Alaska North Slope Cost Discrepancy

Task EPA Cost CPAI Cost

Round Trip Airfare to Alaska North Slope per

person

N/A ~$800a

Per Night Room and Board per person N/A $180

Average LDAR per WS (outside contractor

survey and repairs only)

$951 $7,539b

Average LDAR per Gathering and Boosting

CS (outside contractor survey and repairs only)

$5,938 >$37,695c

a Based on published commercial fares. Actual cost is lower, but still substantial.

b Cost based on actual surveys and repairs conducted within the 2017 year.

c Cost estimated at five times the amount of an average WS survey. This is suspected to be an

underestimation of the cost at a single CPF.

Given the remote nature and size of our operations, much more planning and logistics are involved,

therefore leading to much higher costs than EPA anticipated.

EPA estimated the leak rate from the Alaska North Slope facilities to be 2.38 percent using

information supplied by the American Petroleum Institute (API). This estimate does not fairly

represent Alaska North Slope operations. The majority of actual component counts for the Alaska

North Slope were not provided to EPA for the API analysis because that information is not readily

available at most sites. In the absence of actual component counts, estimated component counts

were calculated based on major equipment counts. Using major equipment counts underestimates

the number of components because there is no good estimate for certain types of infrastructure on

these sites (such as manifold buildings, where most components are located).

CPAI has actual component counts for three WSs. The actual component counts were completed

as a part of the ICR as mentioned above. Those three WSs are characterized by CPAI as a small,

medium, and large WS. Two of these WSs are currently subject to OOOOa, and their leak rates

from the first survey conducted are 0.02% and 0.12%. Using the information from the ICR, CPAI

believes 7,073 components (an average of the three WSs) is a representative number of

components per WS across the Alaska North Slope. Using this number for every Alaska North

Slope WS, and the actual number of leaking components from the API analysis, the

overall average

leak rate for Alaska North Slope WSs would have been 0.23%. CPAI believes this number to be

much more representative of the typical WS on the Alaska North Slope, and it is only about onetenth

the rate estimated by EPA. Though Alaska North Slope operations are large (thousands of

components per WS), the leak rate is low.

Given the unique operations on the Alaska North Slope and the challenge of verbalizing the

uniqueness to inform the creation of workable and efficient regulations, CPAI would like to extend

an open invitation to EPA to visit our Alaska North Slope operations and gain firsthand knowledge

of our operating environment.